

Acid Gas Injection in the Alberta Basin: a Commercial-Scale Analogue for CO₂ Geological Sequestration in Sedimentary Basins

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INTRODUCTION

Geological sequestration of carbon dioxide is an option for significantly reducing CO₂ emissions into the atmosphere that is immediately available and technologically feasible as a result of the experience gained in CO₂-flood enhanced oil recovery, mainly in Texas, and in lesser-known acid-gas injection operations in Rocky Mountain foreland basins. Over the past decade, oil and gas producers in the Alberta basin in western Canada (Alberta and British Columbia) have been faced with a growing challenge to reduce atmospheric emissions of hydrogen sulphide (H₂S), which is produced from “sour” hydrocarbon pools. Sour oil and gas are hydrocarbons that contain H₂S and CO₂, which have to be removed before the produced oil or gas is sent to markets. Because surface desulphurization is costly and the surface storage of the produced sulphur constitutes a liability, increasingly more operators are turning to acid gas disposal by injection into deep geological formations. Acid gas is a mixture of H₂S and CO₂, with minor traces of hydrocarbons, that is the byproduct of “sweetening” sour hydrocarbons. In addition to providing a cost-effective alternative to sulphur recovery, the deep injection of acid gas reduces atmospheric emissions of noxious substances and alleviates the public concern resulting from sour gas production and flaring.

The first acid-gas injection operation in the world was started in 1989 on the outskirts of Edmonton, Alberta. By the end of 1994, there were four acid-gas injection schemes in operation, with another 12 in the process of application review. To date, 42 acid-gas injection operations have been approved in western Canada (35 in Alberta and 7 in British Columbia) for acid gas injection at 47 sites (at a few operations injection takes place at several locations or into two different formations). Thirty-nine operations were active at the end of 2002. One operation in Alberta, although approved, was never implemented by the operator. Another operation has been rescinded by the operator because the gas plant producing the acid gas has been decommissioned. At another operation with multiple sites in northern Alberta, injection into two reefal carbonate reservoirs was shut down by the regulatory agency because the operator greatly exceeded the approved injection volume or pressure. No safety incidents have been reported to the regulatory agencies in Alberta and British Columbia in the 13 years since acid gas injection started in western Canada. Figure 1 shows the location of acid-gas injection operations in western Canada at the end of 2002.

Although the purpose of the acid-gas injection operations is to dispose of H₂S, significant quantities of CO₂ are being injected at the same time because it is costly to separate the two gases. Actually, more CO₂ than H₂S has been injected to date into deep geological formations (Figure 2). In the context of current efforts to reduce anthropogenic emissions of CO₂, the acid-gas injection operations in western Canada represent a commercial-scale analogue to geological sequestration of CO₂. For land-locked regions located on sedimentary basins, such as the North American mid-continent, CO₂ geological sequestration is an immediately-available and technologically-feasible means of reducing CO₂ emissions into the atmosphere (Bachu, 2003). Large-scale injection of CO₂ into depleted oil and gas reservoirs and into deep saline aquifers is one of the most promising methods of geological sequestration of CO₂, and in this respect it is no different from acid-gas injection operations. Given the nature of H₂S, which is more toxic and corrosive than CO₂, the success of these acid-gas injection operations indicates that the engineering technology for CO₂ geological sequestration is well developed and ready for large-scale deployment. However, before implementation of greenhouse gas geological sequestration, a series of questions need to be addressed: the most important ones relating to the short- and long-term fate of the injected CO₂. The acid-gas injection operations in western Canada provide the opportunity to learn about the characteristics and safety of these operations, and represent a unique opportunity to investigate the feasibility of CO₂ geological sequestration.

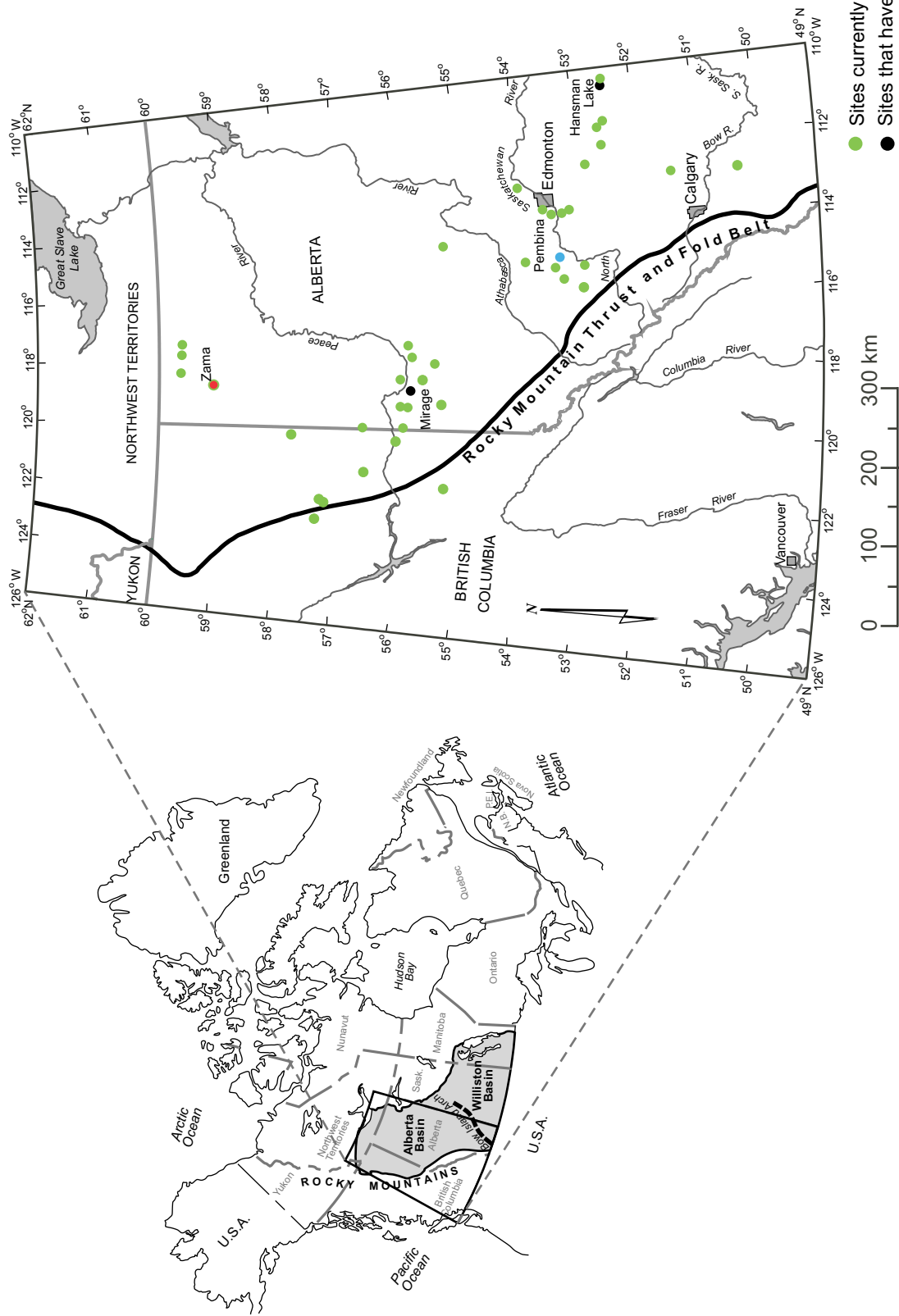


Figure 1. Location and status of the acid-gas injection operations in the Alberta basin, Canada, at the end of 2002.

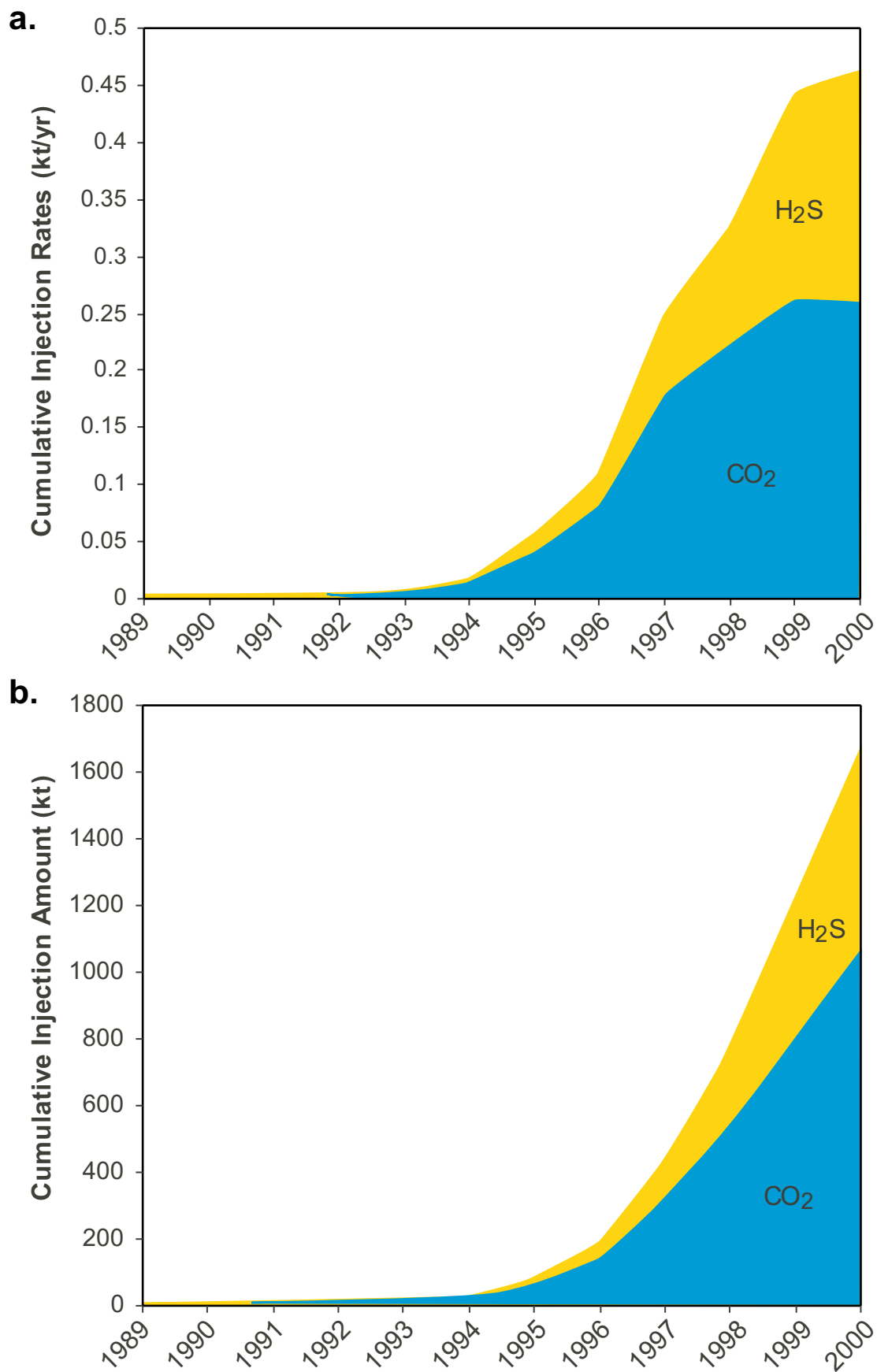


Figure 2. Cumulative amount (all sites) of CO₂ and H₂S actually-injected into deep aquifers and reservoirs in the Alberta basin, Canada, to the end of 2000: a) injection rate, and b) mass.

ACID GAS PROPERTIES

The surface operations and the subsurface aspects of acid gas injection depend on the properties of the H₂S and CO₂ mixture, which include, but are not limited to non-aqueous phase behavior, water content, hydrate formation, and the density and viscosity of the acid gas (Carroll & Lui, 1997; Ng *et al.*, 1999). While there are not many publications on the properties of the acid gas mixture, the properties of pure CO₂ and H₂S have been thoroughly examined and reported. In their pure state, CO₂ and H₂S have similar phase equilibria, with CO₂ condensing at lower temperatures than H₂S (Carroll, 1998a). The phase behavior of the acid-gas binary system is represented by a continuous series of two-phase envelopes (separating the liquid and gas phases) located between the unary bounding systems in the pressure-temperature space (Figure 3a). If water is present, both CO₂ and H₂S form hydrates at temperatures up to 10°C for CO₂ and more than 30°C for H₂S (Carroll & Lui, 1997). If there is too little water, all of the water dissolves in the acid gas and hydrates will generally not form. However, phase diagrams show that hydrates can form without free water being present (Carroll, 1998a,b), thus operating above the hydrate-forming temperature is desirable.

The properties of the acid gas mixture are important in facility design and operation because, to optimize sequestration and minimize risk, the acid gas needs to be injected: (1) as a dense-fluid phase, to increase sequestration capacity and minimize buoyancy; (2) at bottom-hole pressures greater than the formation pressure, for injectivity; (3) at temperatures in the system generally greater than 35°C to avoid hydrate formation, which could plug the pipelines and well bore; and (4) with a water content lower than the saturation limit, to avoid corrosion. For the acid-gas injection operations in western Canada, the in-situ temperature and licensed injection pressure position these characteristics in the P-T space between the supercritical points for CO₂ and H₂S (Figure 3a). The composition of the acid gas licensed for injection varies between 15 mol% CO₂ and 85 mol% H₂S, and 98 mol% CO₂ and 2 mol% H₂S (Figure 3b).

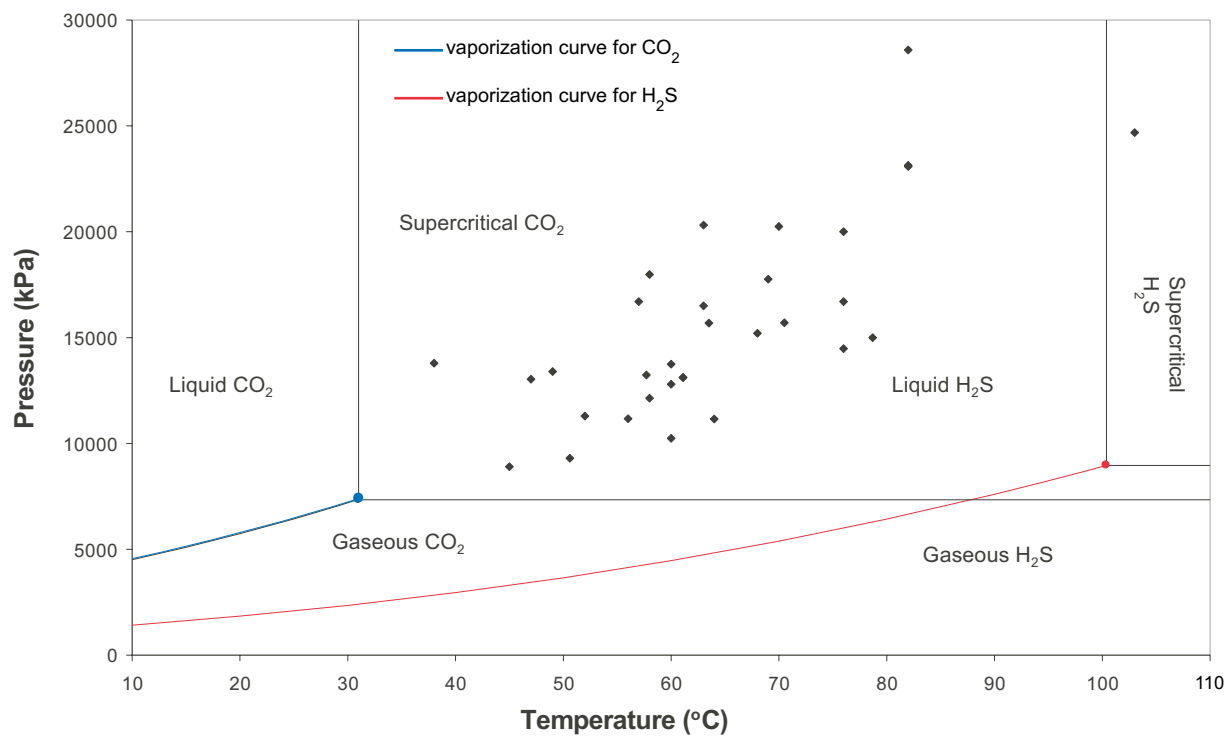
SITE SELECTION FOR ACID GAS INJECTION

In Alberta, applications for acid gas disposal must conform to the specific requirements listed in Chapter 4.2 of Guide 65 that deals with applications for conventional oil and gas reservoirs (AEUB, 2000). Requirements in B.C. are modeled after those in Alberta. The selection of an acid-gas injection site needs to address various considerations that relate to: proximity to sour oil and gas production that is the source of acid gas; confinement of the injected gas; effect of acid gas on the rock matrix; protection of energy, mineral and groundwater resources; equity interests; wellbore integrity and public safety (Keushnig, 1995; Longworth *et al.*, 1996).

The sweetening of sour gas takes place at gas plants where the natural gas is processed to meet pipeline and sales specifications. After separation of any gas liquids, the sour gas is flowed through a contactor or absorber tower in a one- or two-stage process where the sour gas typically comes in contact with an amine solution. The amine reacts with the acid gas, dissolving it, trapping it in the water phase, and allowing the sweet components of the natural gas to pass through. The gas-saturated amine solvent is collected from the bottom of the tower and is regenerated by heating the aqueous solution to approximately 170°C. The water-saturated acid-gas stream leaves the regeneration unit at 35 to 70 kPa and must be cooled and then compressed to pressures in excess of the pressure in the target formation. Typically, four stages of compression are required to provide the required discharge pressure (Figure 3). To avoid pump cavitation, the acid gas must not enter the two-phase region during compression. The high pressures after the fourth compression stage stabilize, upon cooling, the high-density liquid-phase of the acid gas, which can have a density of approximately 75% of water density, if the hydrocarbon content is not greater than approximately 2 mol%. Once the acid gas is compressed, it is transported through a pipeline to the injection well, usually at a short distance from the gas plant.

The specific location of the acid-gas injection well is based on a general assessment of the local and regional geology and hydrogeology, which is designed to evaluate the potential for leakage (Longworth *et al.*, 1996) and which includes:

a.



b.

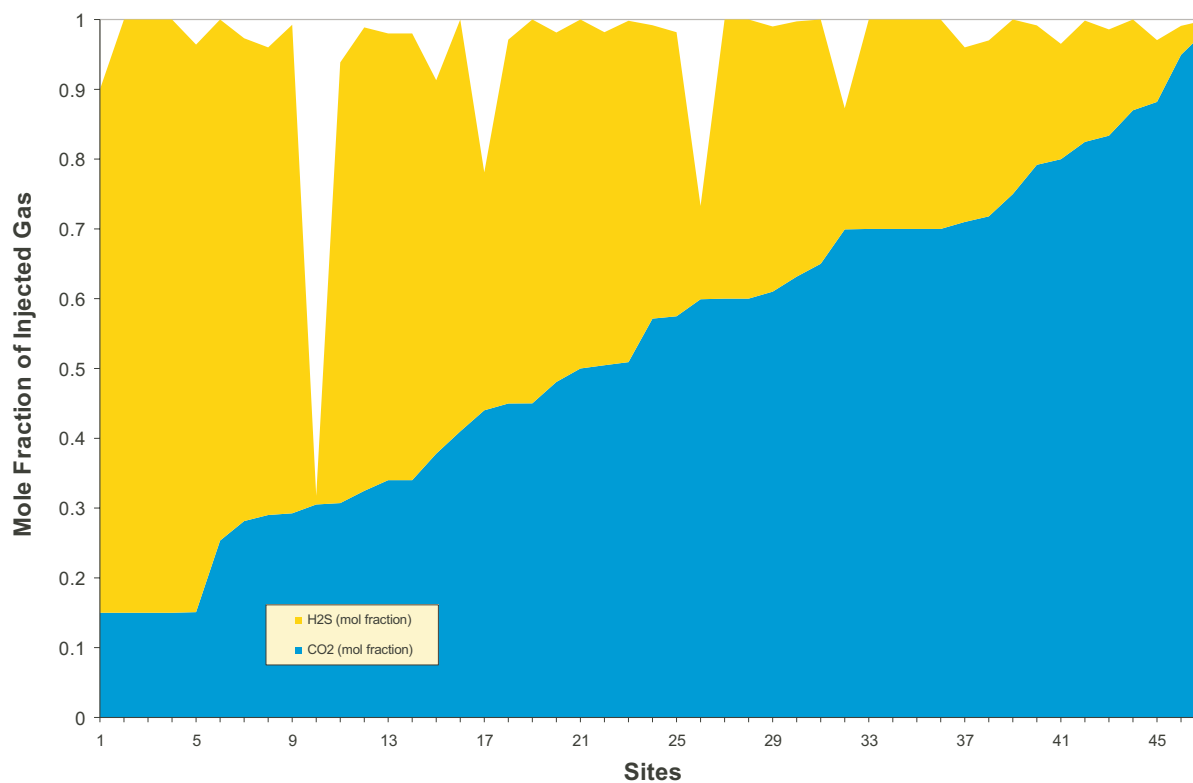


Figure 3. Properties of the acid gas injected in the Alberta basin, Canada: a) pressure and temperature, and b) composition.

1. size and geometry of the injection zone, to confirm that it is large enough to volumetrically hold all of the injected acid gas over the project lifetime;
2. thickness and extent of the overlying confining layer (caprock);
3. location and extent of the underlying or lateral bounding formations;
4. folding, faulting, and fracturing in the area, and an assessment of seismic (neotectonic) risk that may affect the containment of acid gas;
5. rate and direction of the natural flow system, to assess the potential for migration of the injected acid gas;
6. permeability and heterogeneity of the injection zone;
7. chemical composition of the formation fluids (water for aquifers, oil or gas for reservoirs);
8. formation temperature and pressure;
9. analyses of formation and caprock core (if available); and, finally,
10. a complete and accurate drilling history of offsetting wells within several km of the injection well, to identify any wells or zones that may be impacted by the injected acid gas.

In addition, the regulatory agencies require that environmental concerns must be addressed, such as injection-formation suitability, wellbore integrity, operating parameters (to ensure formation and well integrity), and optimization of the injection space, which is considered to be a limited resource.

Knowledge of the geological setting and characteristics is critical for assessment of the integrity of the host formation or reservoir, and the short- and long-term fate of the injected acid gas. Of particular importance are potential migration pathways from the injection zone to other formations, shallow groundwater and/or the surface. These potential pathways are of three types: the caprock pore space (“membrane” type), natural and/or induced fractures (“cracks”) through the confining strata, and improperly completed and/or abandoned wells (“punctures”). To avoid diffuse gas migration through the caprock pore space, the difference between the pressure at the top of the injection aquifer or reservoir and the pressure in the confining layer must be less than the caprock threshold displacement pressure, which is the pressure needed for the acid gas to overcome the capillarity barrier and displace the water that saturates the caprock pore space. To avoid acid gas migration through fractures, the injection zone must be free of natural fractures, and the injection pressure must be below a certain threshold to ensure that fracturing is not induced. The maximum bottomhole injection pressure is set by regulatory agencies in western Canada at 90% of the fracturing pressure. In the absence of site-specific tests, the pressures are limited by pressure-depth correlations, which are based on basin-wide statistical data for the Alberta basin. From this point of view, injection into a depleted oil or gas reservoir has the advantages of injection pressures being low and of wells and pipelines being already in place (Keushnig, 1995).

SUBSURFACE CHARACTERISTICS OF ACID-GAS INJECTION OPERATIONS

The acid-gas injection sites in the Alberta basin are located mostly close to the Rocky Mountain Thrust and Fold Belt, in a region that corresponds to sour gas production from deep reservoirs (Figure 1). Two sites in B.C. are actually located within the thrust and fold belt. The sites meet the criteria for and are located in areas suitable for CO₂ sequestration in geological media in the Alberta basin (Bachu, 2000; Bachu & Stewart, 2002). At 26 sites the acid gas is injected into deep saline aquifers in regional-scale flow systems, which are confined by regional-scale aquitards. At 17 sites injection took or takes place in depleted oil and/or gas reservoirs, and at 4 sites the acid gas is injected into the underlying water leg of depleted oil and gas reservoirs. The acid gas is or was mixed with water at surface, prior to injection, at 6 sites. Of these, two are actually water disposal sites with a minor amount of dissolved acid gas (“sour water” disposal), while a strong acid gas solution is injected at the other 4 operations. Pure acid gas, with minor hydrocarbons, is injected at all other operations. In the case of injection into hydrocarbon reservoirs, the acid gas could increase oil or gas recovery if it is injected to maintain reservoir pressure (Longworth *et al.*, 1996; Connock, 2001). Actually, a mixture of 20% H₂S and 80% CO₂ miscible with reservoir oil was used in the late 1990’s at an acid-gas injection operation in northern Alberta to enhance oil recovery (Davison *et al.*, 1999). To date, the largest operation in the Alberta basin, which is also the largest in the world, has a licensed capacity of 391,000 m³/d, but operates only at 280,000 m³/d. The acid gas stream contains 85% H₂S and 15% CO₂ (340 and 78 t/d H₂S and CO₂, respectively).

The depth of the injection zone varies mostly in the 1100-2300 m range, although in a few cases it is as shallow as 705 m, and as deep as 3478 m. The shallow injection zones (705 m to 913 m depth) correspond to sour water injection. The thickness of the injection zone, as defined geologically, varies between 4 and 276 m; however, the actual net pay, defined by rocks with porosity and permeability adequate for injection, reaches only 100 m. At 28 sites the acid gas is injected into deep carbonate formations, mostly platform carbonates but also a few carbonate reefs, and at 19 sites the injection is into sandstones. Shales constitute the overlying confining unit (caprock) in most cases, although tight limestones, evaporites and anhydrites form the caprock in some instances. Caprock thickness varies between 2 and 270 m. The rock porosity of the injection zone varies between 4% and 30% (Figure 4a). The platform carbonates generally have lower porosity (5%-10%), while the carbonate reefs have porosity in the 15-22% range. Only the porosity of sandstones exhibits a general trend of decreasing porosity with increasing depth from 30% to 8%. Rock permeability is indicated for less than half of the sites and varies from as low as 0.55 md to as high as 10,400 md, although most values are of the order of 10-100 md.

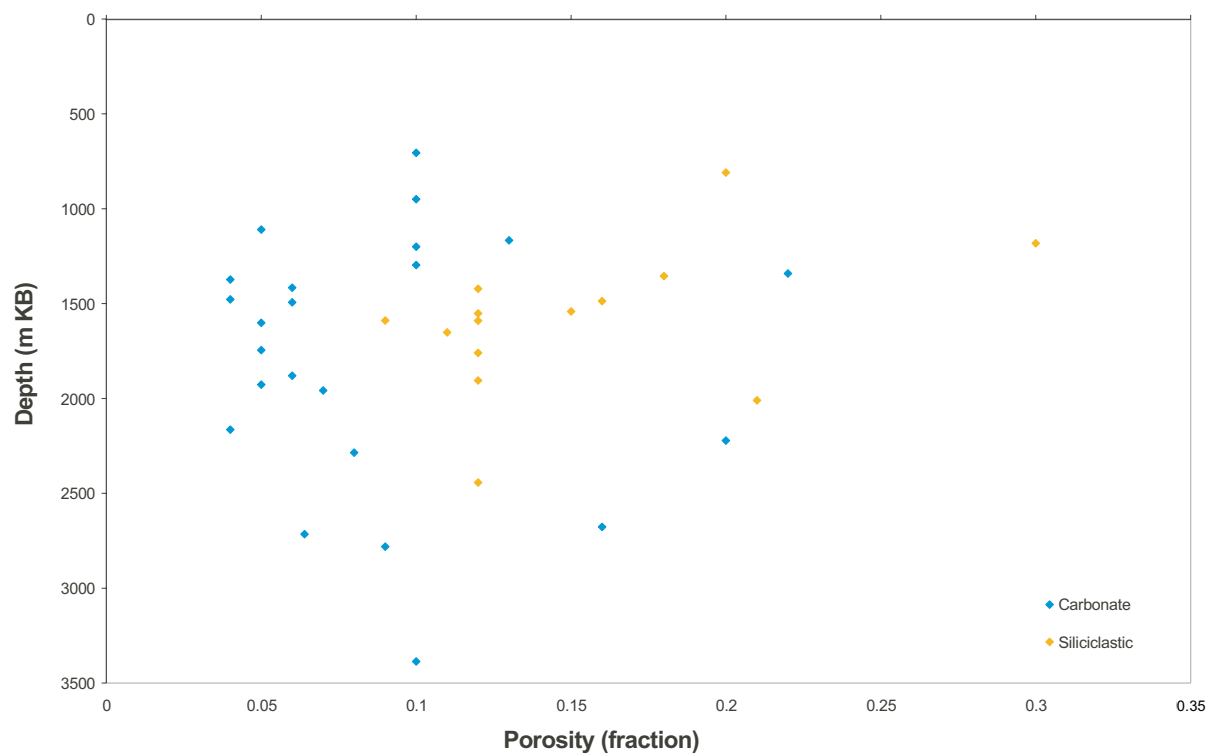
Generally formation waters are very saline, with salinity varying in a very wide range, from ~24,000 mg/l to ~341,000 mg/l (Figure 4b). Although there is a broad trend of increasing salinity with depth, exceptions are due to the injection zones being influenced by the influx of fresher water, or by the proximity of evaporitic beds. The case of very high salinity encountered at a relatively shallow depth corresponds to injection into a carbonate aquifer overlain by thick halite beds. For the case of acid gas being injected into depleted oil reservoirs, the oils are medium to very light (33°API to 68°API). Reservoir gases are generally light (specific gravity less than 0.75) except for four cases of 0.851, 0.915, 1.024 and 1.121.

The original formation pressure is generally subhydrostatic with respect to freshwater, which is characteristic of the Alberta basin (Bachu, 1999), and, except for one very low case of 5915 kPa that actually corresponds to a sour-water injection operation, varies between 8900 kPa and 35,860 kPa (Figure 5a). The cases where pressure seems to be slightly above hydrostatic correspond actually to high salinity formation waters. If the real formation water density is taken into account, then pressures at all but three sites are hydrostatic or less. Two cases of above-hydrostatic pressures correspond to reefal gas reservoirs. The only overpressured case is for injection into a deep structural trap in the thrust and fold belt of the Rocky Mountains in British Columbia (Figure 1). In the case of acid gas injection into depleted oil or gas reservoirs, the original reservoir pressure has been drawn down as a result of production, such that formation pressure at the start of acid gas injection may have been less than the original formation pressure, sometimes significantly, reaching values as low as 1170 kPa. Production-induced drawdown occurs also in the case of injection into an aquifer underlying an oil pool, and into an aquifer located very close to an oil pool. In 10 cases formation pressure at start up was below the critical pressure of CO₂.

Formation temperature varies between 35°C at 1397 m depth and 110°C at 3432 m depth (Figure 5b), although higher temperatures are recorded at shallower depths (e.g., 56°C at 1138 m), and a relatively low temperature (82°C) is indicated for a deep injection zone (2450 m). The spread in temperature variation with depth for the acid-gas injection zones is due to the variability in geothermal gradients across the Alberta basin, characterized by a trend of increasing gradients from the south, where they are as low as 20°C/km, to the north, where they reach more than 50°C/km (Bachu, 1993).

The porosity and permeability of the acid-gas injection formations in western Canada are significantly lower, and pressures and temperatures are significantly higher than those of the Utsira aquifer in the North Sea at Sleipner West (Pearce *et al.*, 2001), where CO₂ is injected into a weakly-compacted formation in an off-shore cratonic basin (Zweigel *et al.*, 2001). The porosity, permeability, pressure and temperature values characteristic of the acid-gas injection operations in the Alberta basin are much more representative of aquifers and reservoirs in continental sedimentary basins that have undergone compaction and erosion. It is in these environments that CO₂ injection and geological sequestration on a large scale is most likely to be implemented first, at least in North America.

a.



b.

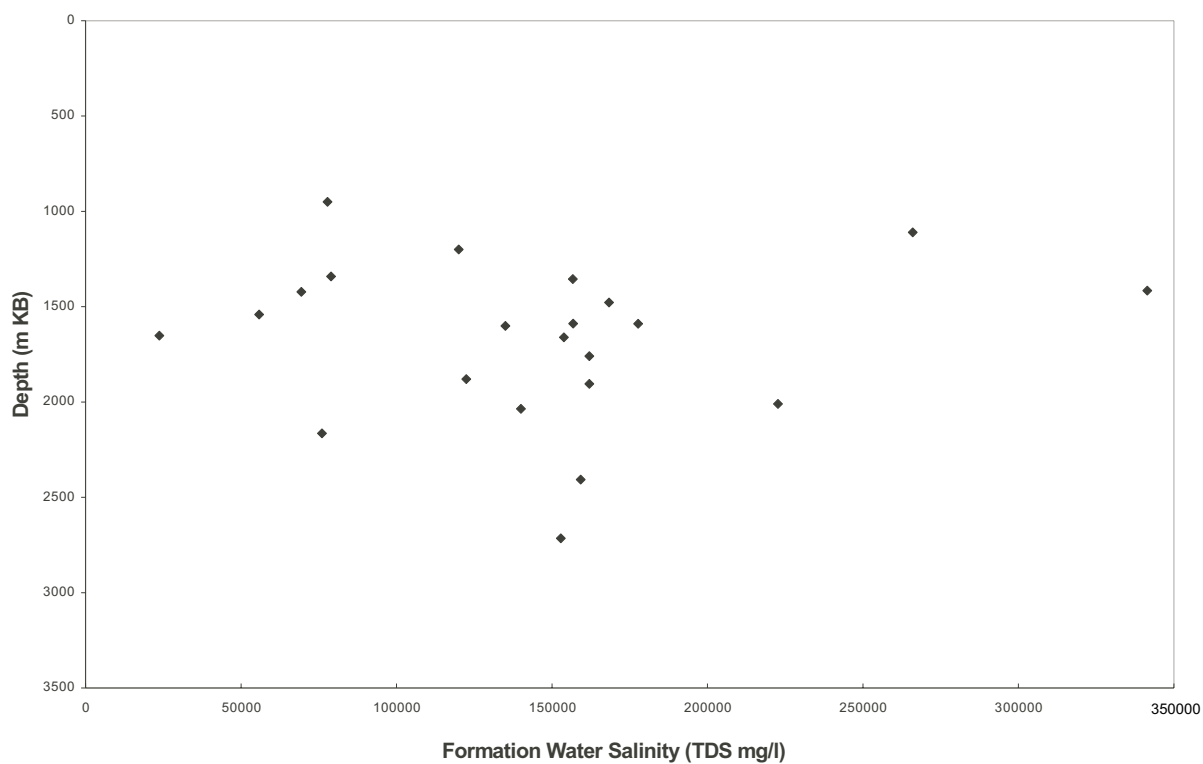


Figure 4. Properties of the host aquifer or reservoir into which acid gas is injected in the Alberta basin, Canada: a) rock porosity, and b) salinity of formation water.

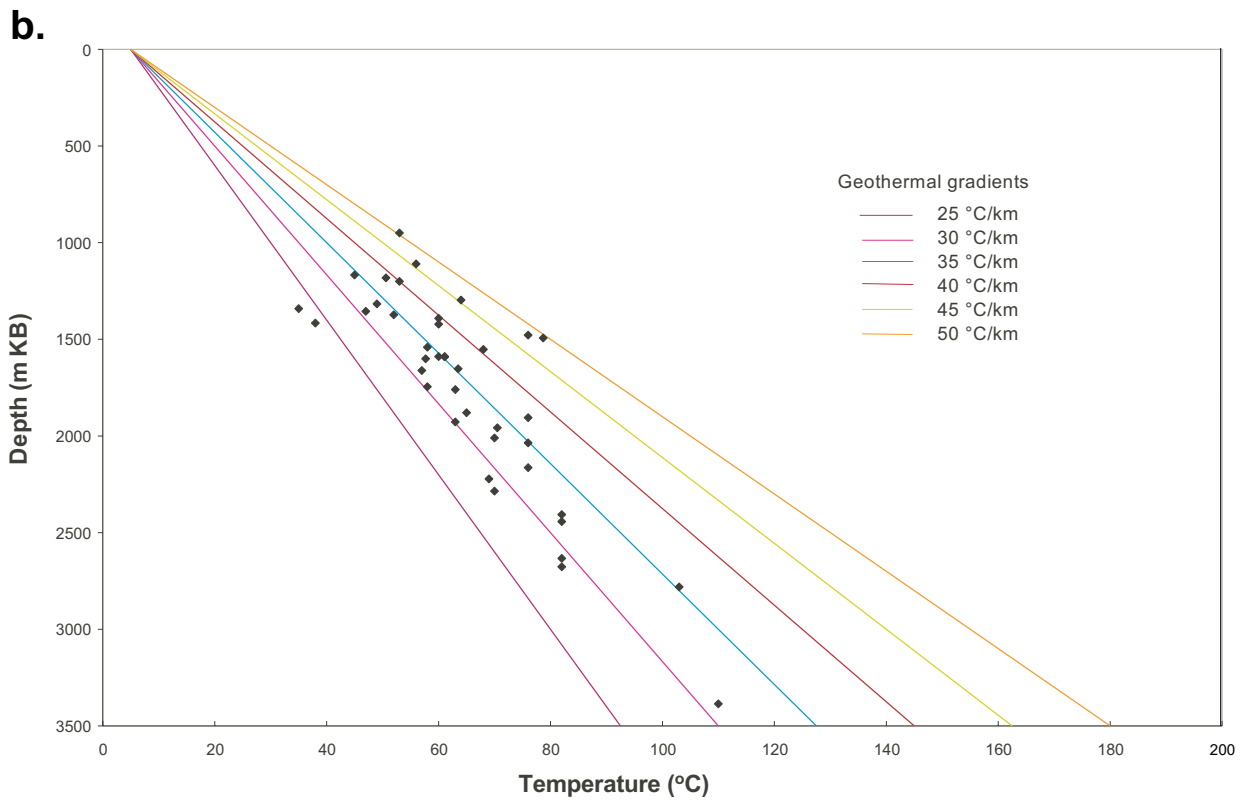
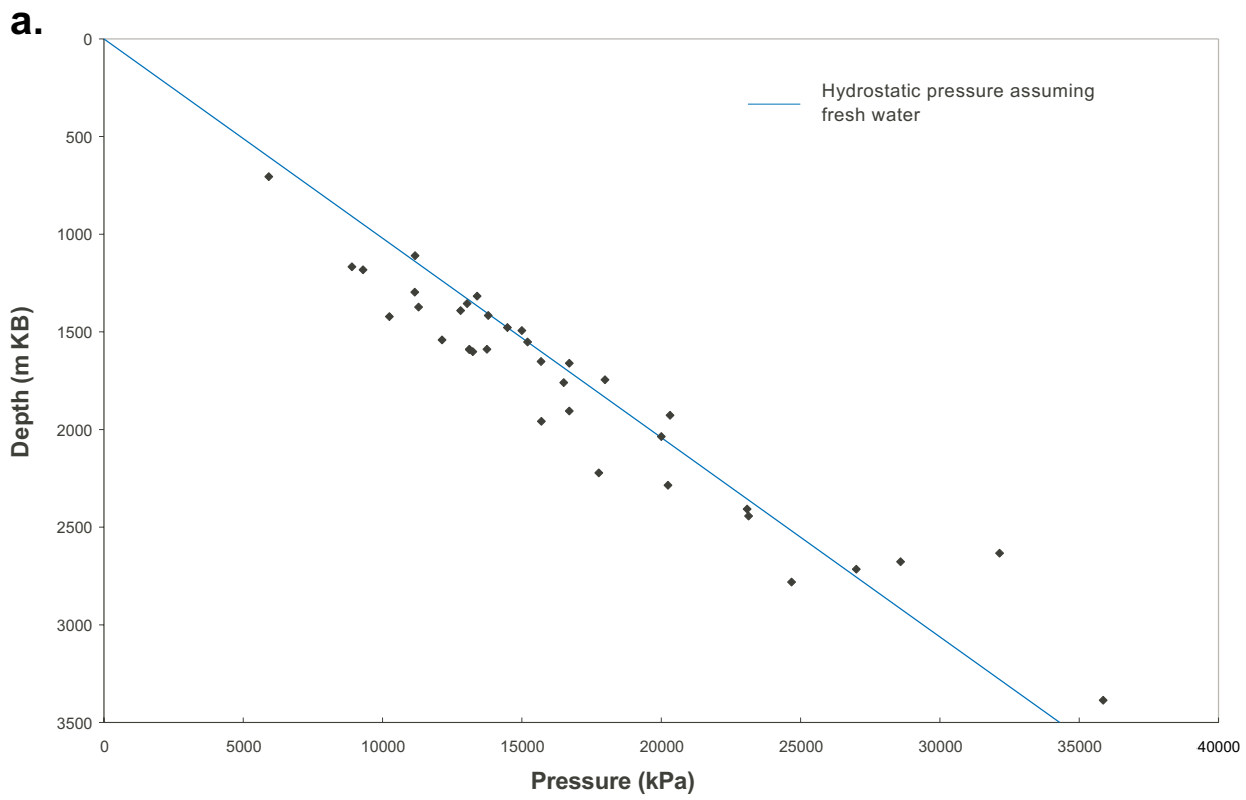


Figure 5. Subsurface P - T characteristics of the acid-gas injection operations in the Alberta basin, Canada: a) formation pressure, and b) formation temperature.

CONCLUSIONS

Geological sequestration of CO₂ is a mitigation option for significantly reducing CO₂ emissions into the atmosphere that is immediately available and technologically feasible. Injection technologies have been developed for the storage of petroleum products and natural gas, and disposal of hazardous wastes. Various operations in North America inject CO₂ in deep formations, either for enhanced oil recovery (mostly in the Permian basin in Texas), or for acid gas disposal (mostly in the Alberta basin in western Canada). The geological conditions at these operations are truly representative of the general conditions encountered within on-shore sedimentary basins.

Currently, acid gas injection in the Alberta basin occurs over a wide range of aquifer and reservoir characteristics, acid-gas composition, and operating conditions. The size of the 42 acid-gas injection operations approved to date in western Canada is relatively small, with approved injection rates and volumes generally less than 0.1 million m³/d and 200 million m³, respectively. However, close to 1.5 Mt CO₂ and 1 Mt H₂S have been successfully injected to date into deep hydrocarbon reservoirs and saline aquifers in Canada alone. Together with the 16 or so acid-gas injection operations in the United States, these acid-gas injection operations constitute a perfect analogue for large-scale CO₂ geological sequestration. The range of depth, temperature and pressure, and the rock characteristics of these injection operations show that CO₂ can be safely injected at great depths, thereby achieving higher CO₂ density and increasing the sequestration capacity. Safety is also increased at greater depth by lowering CO₂ buoyancy, hence the CO₂ migration potential, by lengthening the flow path and by increasing the number of barriers to migration, such as intervening aquitards.

The experience of acid-gas injection operations shows that CO₂ sequestration in geological media is a mature and safe technology that can successfully be expanded to and applied in large-scale operations that will reduce CO₂ emissions into the atmosphere from large CO₂ point sources. The technology and experience developed in the engineering aspects of acid-gas injection operations (i.e., design, materials, leakage prevention and safety) can be easily adopted for large-scale operations for CO₂ geological sequestration, since a CO₂ stream with no H₂S is less corrosive and hazardous. Although the fate of the injected acid gas has not been monitored to date, the subsurface information about aquifer and reservoir rocks and fluids may provide a wealth of information as to the characteristics of a good CO₂-sequestration site. This information can be used for the screening and identification of future sites for the geological sequestration of CO₂. In addition, monitoring the fate of the injected acid gas at one or more such sites will provide invaluable information about the long-term fate of injected acid and greenhouse gases.

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